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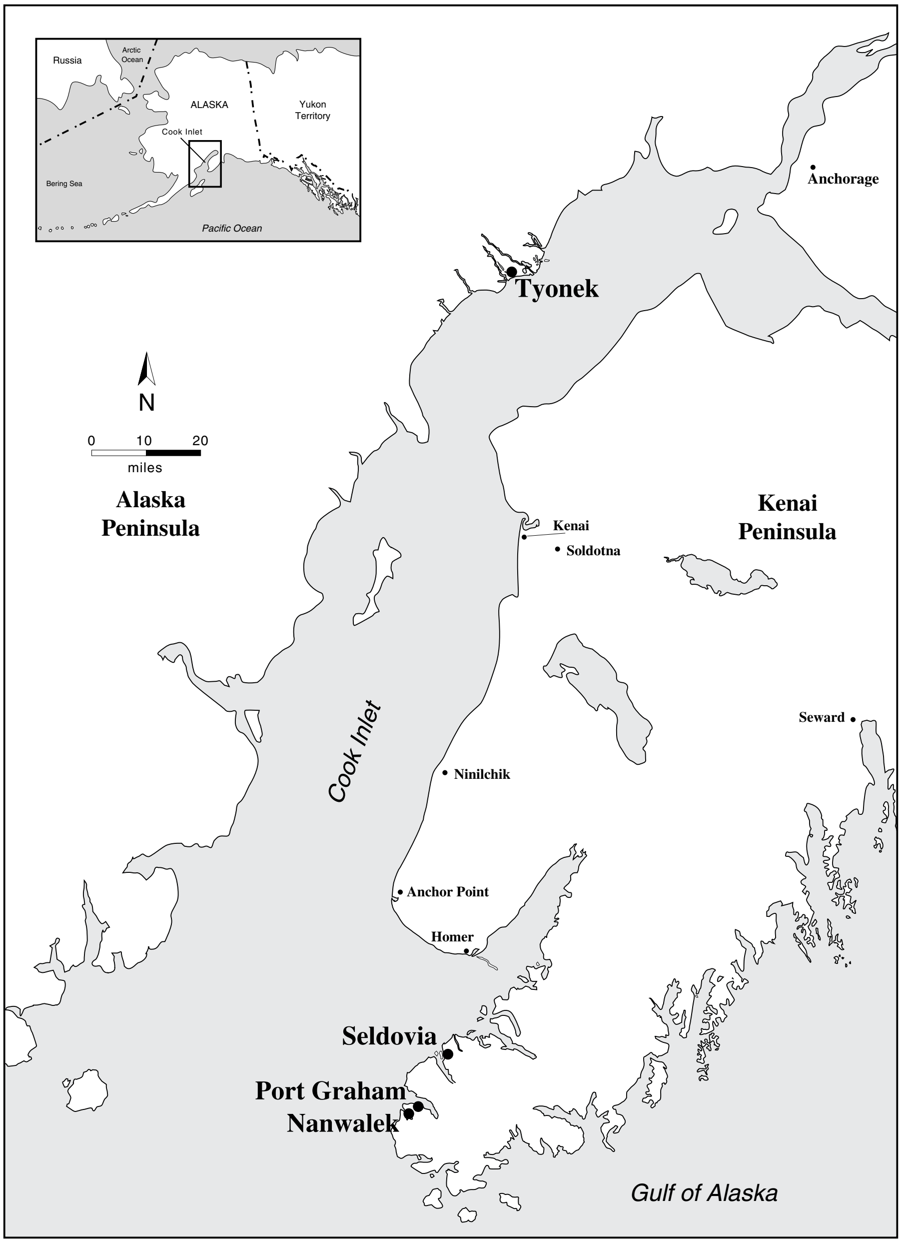
Appendix D

Copied pages from "Development Document for Final Effluent Limitations Guidelines & Standards for the Coastal Subcategory ...."



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United States
Environmental Protection
Agency

Office of Water

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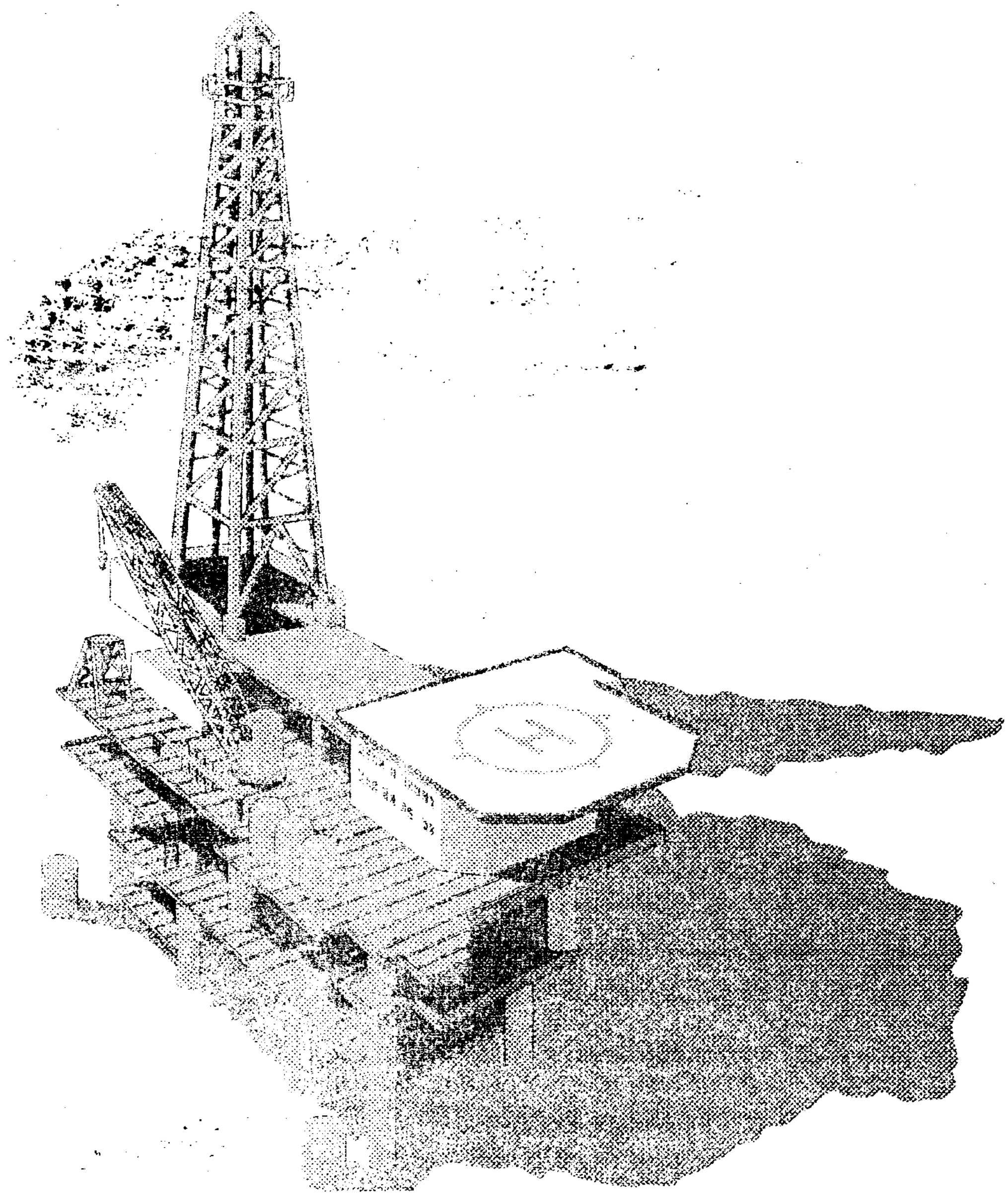
Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category



discharges of wastes from within the reserve pit would be required to comply with the zero discharge limitations of the rule.

The technical aspects of dewatering liquid generation are discussed in greater detail in Sections 5.5.5 and 5.5.6.

3.0 DRILLING WASTE VOLUMES

Approximately 89,000 bbls per year of drilling fluids and cuttings are being discharged by the coastal oil and gas industry, all of which is occurring in Cook Inlet. All other coastal areas are prohibited from discharging drilling wastes. Thus, approximately 626,000 barrels of drilling fluids and cuttings will be discharged from all of the Cook Inlet drilling projects currently planned by industry extending until the year 2002. The following sections discuss the factors affecting the volumes of drilling waste generated and numerical estimates of these volumes.

3.1 FACTORS AFFECTING DRILLING WASTE VOLUMES

Drilling fluids discharges are typically in bulk form and occur intermittently during well drilling and at final well depth. Low volume bulk discharges are the most frequent and are associated with fluid dilution, the process of maintaining the required level of solids in the fluid system. High volume bulk discharges occur less frequently during a well drilling operation, and are associated with drilling fluid system changeover and/or emptying of the mud tank at the end of the drilling program.

The volume of drilling fluid generated and the volume of drill cuttings recovered at the surface will depend on the following:

- Size and type of drill bit
- Hole enlargement
- Type of formation drilled
- Efficiency of solids control equipment
- Type of drilling fluid
- Density of drilling fluid.

The EPA Offshore Oil and Gas Development Document describes the effect of each of these factors on drilling fluid volume.[4]

The volume of drill cuttings generated depends primarily on the dimensions (depth and diameter) of the well drilled and on the percent washout. Washout is the enlargement of a drilled hole due to the sloughing of material from the walls of the hole. Drill solids are continuously removed via the solids control equipment during drilling. The greatest volumes of drill cuttings are generated during the initial stages of drilling when the borehole diameter is large and washout tends to be higher. Continuous and intermittent discharges are normal occurrences in the operation of solids control equipment. Such discharges occur for periods from less than one hour to 24 hours per day, depending on the type of operation and well conditions.

The volume of drill cuttings generated also depends on the type of formation being drilled, the type of bit, and the type of drilling fluid. Soft formations are more susceptible to borehole washout than hard formations. The type of drilling fluid used can affect the amount of borehole washout and shale sloughing. The type of drill bit determines the characteristics of the cuttings (particle size). Depending on the formation and the drilling characteristics, the total volume of drill solids generated will be at least equal to the borehole volume, but is most often greater due to the breaking up of the compacted formation material.

Additional information regarding hole enlargement due to washout is listed in Table VII-1. These data were provided to EPA by drill site operators during visits to three coastal sites in southern Louisiana.[1,2,3] Because the volume of washout varies depending on the type of formation being drilled, no single set of numbers can be applied as a rule of thumb to all drilling situations. However, Table VII-1 indicates that the percent washout generally decreases with hole depth. It should be noted that the values in Table VII-1 were estimates obtained from industry operators during EPA's drilling site study and were not directly measured.

3.2 ESTIMATES OF DRILLING WASTE VOLUMES

In order to compare waste volumes generated during various drilling projects, a normalized waste volume can be determined by dividing the total reported waste discharged from the active drilling fluid circulation system by the total volume of hole drilled. The volume of hole drilled is calculated from the bit sizes used for specific depth intervals, and from estimated washout volumes. The volume of waste

TABLE VII-1

PERCENT WASHOUT FACTORS

Reference	Depth Interval (feet)	Percent Washout
SAIC, May 25, 1994[1]	0 - 3,000	100
	3,000 - 11,500	25-50
	> 11,500	10
SAIC, Aug. 8, 1994[2]	0 - 4,000	75
	4,000 - 11,000	40
	11,000 - 13,000	20
	> 13,000	10
SAIC, Aug. 5, 1994[3]	0 - 3,000	100
	3,000 - 10,000	50
	> 10,000	25-50

discharged is typically available from waste transport reports or other records maintained at the drill site, and are often estimated based on the volume of the vessel used to store and/or transport the waste. Once calculated, the ratio of waste-to-hole volume can then be compared between drilling projects. For drill cuttings, this ratio is called the "expansion factor" because it indicates how much a given volume of cuttings increased after it was drilled out of the hole. No such distinctive name is used for the ratio of waste drilling fluid to calculated hole volume. For both drilling fluids and cuttings, the waste-to-hole volume ratio should always be greater than one, although in some cases it is less than one due to the disposal of fine cuttings with the waste fluid, or to inaccurate waste volume tracking procedures or records. Table VII-2 lists the hole volumes, waste volumes, and the calculated waste-to-hole volume ratios for eight different drilling projects in the coastal Gulf of Mexico region. The first three projects were created based on a "model well" as part of EPA Region 6's development of two general NPDES permits for coastal Louisiana and Texas (55 FR 23348), and were not actual wells drilled. The characteristics of the model well (e.g., depth intervals, hole volume, percent washout, etc.) and the solids control system parameters were designed to represent typical coastal drilling projects. The remaining five projects in Table VII-2 were actual wells, including two offshore and three coastal.

TABLE VII-2

WASTE DRILL CUTTINGS AND DRILLING FLUID VOLUMES

Reference	Closed-Loop Solids Control Equipment Efficiency	Well Depth (ft)	Calculated Hole Volume[a] (bbls)	Waste Drilling Fluids Volume[b] (bbls)	Drilling Fluids-to-Hole Ratio (bbls/bbls)	Waste Cuttings Volume[b] (bbls)	Cuttings Expansion Factor[c] (bbls/bbls)
55 FR 23348 (EPA Region 6 general NPDES permit)	Scenario 1: 36%	15,000	1,881	21,220	11.2	2,264	1.20
	Scenario 2: 62%			12,938	6.88	3,301	1.75
	Scenario 3: 90%			3,405	1.81	3,889	2.07
Offshore Operators Committee, 1981[5] (Data for two offshore wells)	50%	10,000	2,453	5,349	2.18	1,430	0.58
		18,000	4,619	10,486	2.27	2,781	0.60
SAIC, May 25, 1994[1] (Data obtained during EPA site visit)	90%	12,860	2,126	2,690	1.27	3,256	1.53
SAIC, August 8, 1994[2] (Data obtained during EPA site visit)	90%	14,928	3,689	5,850	1.59	10,070	2.73
SAIC, August 5, 1994[3] (Data obtained during EPA site visit)	75%	19,260	7,510	8,198	1.09	8,130	1.08
Average	70%	15,000	3,173	8,767	3.54	4,390	1.44

[a] "Hole Volume" was calculated from drilled hole diameter and depth data provided in the references. The data have been adjusted to compensate for hole enlargement due to erosion (washout).

[b] "Discharged Cuttings/Mud Volume" includes the total volume of cuttings or spent drilling fluids that were either discharged or hauled-off by the end of drilling, as reported in the references. These values may be derived estimates or actual data, depending on the reference document.

[c] "Expansion Factor" = Discharged Cuttings Volume (bbls) / Calculated Hole Volume (bbls).

A number of observations can be made from the data in Table VII-2. Referring to the EPA Region 6 data only, it is apparent that as solids control system efficiency increases, the fluid-to-hole volume ratio decreases and the cuttings expansion factor increases. A low efficiency solids control system will allow a significant volume of drill cuttings to remain in the circulating drilling fluid, thus requiring greater dilution of the drilling fluid and hence increasing the volume to be disposed. A higher efficiency solids control system will remove a greater volume of cuttings from the circulating drilling fluid, thus decreasing the need for dilution as well as the volume of waste drilling fluid. In addition, if chemically enhanced centrifugation (CEC) is part of the solids control system, the volume of waste solids should be slightly higher than systems not using CEC because the flocculated solids add to the volume discharged by the centrifuge.

These trends are to be expected, but are not always observed in practice due to site-specific conditions, inaccuracies in hole volume estimation, and in waste volume tracking and reporting. Data from the five actual drilling projects listed in Table VII-2 illustrate this point. The cuttings expansion factors for the two offshore drilling projects are both less than one, suggesting that washout volumes may have been overestimated and that a significant volume of cuttings may have been included with the discharged mud volume. Also, the 8,130 barrels of cuttings reported for the last drilling project in this table is known to include 591 barrels of spent drilling fluid and is believed to include more, particularly because the cuttings were collected in a barge and there was no other holding vessel dedicated to spent drilling fluid at the site. Such uncertainties about what is included in a load of drilling waste and its volume occur because there are no requirements for keeping waste drilling fluid and cuttings volumes separate when they are being hauled offsite.

Volumes of waste drilling muds and cuttings generated by operators located in Cook Inlet, Alaska were reported in responses to the 1993 EPA Coastal Oil and Gas Questionnaire.[6] From the data submitted in the survey and information obtained directly from the operators, an average volume of muds and cuttings generated was calculated to be 14,354 barrels from an average well of 11,765 feet in depth. Table VII-3 lists the data used to calculate these averages.[5]

Based on this estimation and on projected drilling schedules provided by operators in Cook Inlet, the total volume of drilling wastes generated from drilling activities in Cook Inlet is a total of 632,000 bbls over the seven years following promulgation of this rule, or 90,000 bbls per year (see Chapter X for details).

TABLE VII-3

COOK INLET DRILLING WASTE VOLUMES

Operator ID	Depth Interval #1 (feet)	Depth Interval #2 (feet)	Depth Interval #3 (feet)	Total Well Depth (feet)	Muds and Cuttings Volume Int. #1 (bbls)	Muds and Cuttings Volume Int. #2 (bbls)	Muds and Cuttings Volume Int. #3 (bbls)	Total Muds and Cuttings Volume (bbls)
A	1,389	8,477	2,029	11,895	1,528	9,325	2,232	13,085
A	1,256	8,368	2,176	11,800	1,213	8,081	2,101	11,395
A	1,155	8,642	2,343	12,140	1,361	10,180	2,760	14,300
B	2,110	7,999	860	10,969	3,313	7,334	1,334	11,981
B	4,120	5,962	1,478	11,560	Not Available	9,558	1,583	Not Available
B	4,017	5,745	2,068	11,830	6,065	7,606	2,326	15,997
B	3,823	6,240	2,100	12,163	7,504	8,838	3,024	19,366
AVERAGE	**2,553**	**7,348**	**1,865**	**11,765**	**3,497**	**8,703**	**2,194**	**14,354**

Source: EPA, July 1993[6]

3.3 Dewatering Liquid Volumes

Estimates of dewatering liquid volumes were obtained from two of the three drilling operations visited by EPA in 1993.[1,2] Referring to Table VII-2, the wells drilled to depths of 12,860 and 14,928 feet generated estimated volumes of 4,800 and 2,423 barrels of dewatering liquid, respectively. Although a larger hole volume is generally associated with larger volumes of waste fluids and cuttings, there is no apparent relationship between well depth and dewatering liquid volume. As explained in Sections 5.5.5 and 5.5.6, factors affecting the volume and quality of the liquid effluent from a dewatering process are related to the selected dewatering method and the efficiency of the upstream solids separation equipment rather than the well depth. The dewatering liquid from these two drilling operations was either recycled into the active fluid system or hauled off-site for disposal; no dewatering liquid was discharged.

4.0 DRILLING WASTE CHARACTERISTICS

4.1 Drilling Fluid Characteristics

Several broad categories of drilling fluids exist such as water-based fluids (fresh or salt water), low solids polymer fluids, oil-based fluids, and oil emulsion fluids. This section discusses only water- and oil-based fluids because they represent the traditional and most widely used drilling fluids. A newer class of drilling fluids using synthetic materials is discussed later in this chapter (see Section 5.11).

Oil-based drilling fluids are only used for specific drilling conditions because they cannot be discharged and are more expensive to use than water-based drilling fluids. The discharge of oil-based drilling fluids and associated cuttings is prohibited under the BPT limitations of "no discharge of free oil." Industry has indicated that oil-based drilling fluids continue to be the material of choice for certain drilling conditions.[7] These conditions include the need for thermal stability when drilling high-temperature wells, specific lubricating characteristics when drilling deviated wells, and the ability to reduce stuck pipe or hole washout problems when drilling thick, water-sensitive shales. A primary concern when using conventional, oil-based fluid systems is their potential for adverse environmental impact in the event of a spill. Because of the relatively high toxicity of diesel oil, some mineral oil-based fluid systems have replaced diesel oil-based fluids, and as discussed in Section 5.11, synthetic-based drilling fluids are being used in applications previously reliant upon oil-based systems.

Water-based drilling fluids are dense colloidal slurries in a water phase of either fresh or saturated salt mixtures. Salt water-based drilling fluids may be comprised of seawater, sodium chloride ($NaCl$), potassium chloride (KCl), magnesium chloride ($MgCl_2$), calcium chloride/bromide ($CaCl_2$/$CaBr_2$), or zinc chloride/bromide ($ZnCl_2$/$ZnBr_2$). All freshwater fluids contain bentonite (sodium montmorillonite clay) and caustic soda (NaOH), while saltwater fluids may contain attapulgite clay instead of bentonite. Clays are a basic component of drilling fluids used to enhance the fluid viscosity. The most common required drilling fluid properties and the additives used to enhance these properties are discussed below.

Several different formulations of drilling fluids and additives can be created to achieve the required downhole conditions. The most common properties of the drilling fluid that the mud engineer controls are:

- Rheology (flow properties)
- Density
- Fluid loss control
- Lubricity
- Lost circulation
- Corrosion and scale control
- Solvents
- Low solids polymer fluids
- Bactericides.

Each of these properties can be tailored to specific well and drilling conditions through the addition of active solids, inactive solids, and chemicals to the base drilling fluid. The EPA Offshore Development Document discusses each of the above-listed properties, and describes the individual components of drilling fluids as well as typical drilling fluid compositions.[4] A comprehensive list of drilling fluid components and their applications is provided in Appendix VII-1.[8]

Barite, which is used to control the density of drilling fluids, is the primary source of toxic metal pollutants. The characteristics of raw barite will determine the concentrations of metals found in the spent drilling fluid system. A statistical analysis of metals concentrations in spent drilling fluids showed a higher concentration of toxic metal pollutants in drilling fluids formulated with "dirty" barite than in those formulated with "clean" barite.[9]

Based on the results of this analysis, EPA developed a profile of metals concentrations in drilling fluids formulated with "clean" barite as part of the development of Offshore Guidelines. "Clean" barite is defined as stock barite that meets the maximum limitations of cadmium of 3 mg/l and for mercury of 1 mg/l.[4] Table VII-4 presents the estimated characteristics of drilling fluids and cuttings tailored specifically for Cook Inlet since drilling wastes are discharged in this area only. Table VII-4 includes the offshore metals concentration profile developed from the statistical analysis for "clean" barite. The only difference to be noted is the concentration of barium, which was reevaluated in this rulemaking effort because the average weight of drilling fluid (10 lb/gal) reported by Cook Inlet operators in the 1993 EPA Coastal Questionnaire was lower than the average offshore model fluid weight of 11.0 lb/gal. The revised barium concentration for coastal regulations was calculated to be 120,000 mg/kg as compared to the calculated concentration of 359,747 mg/kg estimated for the offshore model well.[10]

Mineral oil, which is used in Cook Inlet drilling operations mostly to free stuck pipe, is a drilling fluid additive that contributes toxic organic pollutants to the drilling fluid system. An operator in Cook Inlet, Alaska estimated that the amount of mineral oil typically used in water-based drilling fluids is approximately 0.02 percent.[6] The concentrations of organic compounds listed in Table VII-4 were calculated based on this estimate,[14] and on the average concentrations of organics in mineral oil as listed in Table VII-9 in the Offshore Development Document.[4]

The TSS attributable to drilling fluids is estimated based on two physical properties of the waste drilling fluids: the estimated percentage of the fluid that is dry solids (11%), and the estimated density of the dry solids (1,025 lbs/bbl).[10] The dry solids content of the drilling fluid was estimated from mud reports provided by the operator of one of the drill sites visited by EPA.[1] The density of dry solids was estimated based on the mud weight of 10.1 lbs/gal obtained from the mud reports,[1] and calculated by subtracting the density of water (in lbs/gal) from the mud weight.[10] Finally, the TSS concentration in drilling fluid was calculated as follows:

(0.11 bbl dry solids/bbl drilling fluid) x (1,025 lbs dry solids/bbl dry solids)
= 113 lbs dry solids/bbl drilling fluid

37,000,000 lbs/

TABLE VII-4

COOK INLET DRILLING WASTE CHARACTERISTICS

Waste Characteristics	Value	Reference
Percent of cuttings in waste drilling fluid	19%	1993 EPA Coastal Oil and Gas Questionnaire[6]
Percent of drilling fluid adhering to cuttings	5%	Ray, 1979[11]
Average density of dry cuttings	980 pounds per barrel	Estimated[12]
Average density of waste drilling fluid	420 pounds per barrel	1993 EPA Coastal Oil and Gas Questionnaire[6] and Calculations[13]
Percent of dry solids in waste drilling fluid, by volume	11%	Calculations[10]
Average density of dry solids in waste drilling fluids	1,025 pounds per barrel	Calculations[10]
Drilling Fluid Pollutant Concentration Data		
Conventionals	**lbs/bbl of drilling fluid**	**Reference**
Total Oil	0.0596	Estimated[14]
Total Suspended Solids	113.0	Estimated[10]
Priority Metals	**mg/kg dry drilling fluid**	**Reference**
Cadmium	1.1	Offshore Development Document, Table XI-6[4]
Mercury	0.1	
Antimony	5.7	
Arsenic	7.1	
Beryllium	0.7	
Chromium	240.0	
Copper	18.7	
Lead	35.1	
Nickel	13.5	
Selenium	1.1	
Silver	0.7	
Thallium	1.2	
Zinc	200.5	
Priority Organics	**lbs/bbl of drilling fluid**	**Reference**
Naphthalene	0.0000035	Calculated[14] from concentrations in Offshore Development Document, Table VII-9[4]
Fluorene	0.0000563	
Phenanthrene	0.0000084	
Non-Conventional Metals	**mg/kg dry drilling fluid**	**Reference**
Aluminum	9,069.9	Offshore Development Document, Table XI-6[4]; except for barium, which was estimated.[10]
Barium	120,000.0	
Iron	15,344.3	
Tin	14.6	
Titanium	87.5	
Non-Conventional Organics	**lbs/bbl of drilling fluid**	**Reference**
Alkylated benzenes	0.0021017	Calculated[14] from concentrations in Offshore Development Document, Table VII-9[4]
Alkylated naphthalenes	0.0000344	
Alkylated fluorenes	0.0001218	
Alkylated phenanthrenes	0.0000143	
Total biphenyls	0.0001360	
Total dibenzothiophenes	0.0000004	

4.2 DRILL CUTTINGS CHARACTERISTICS

Drill cuttings themselves are inert solids from the formation. However, drill cuttings discharges also contain drilling fluids that have adhered to the cuttings. The composition of drill cuttings discharges is directly dependent upon the fluid used. Cuttings associated with oil-based drilling fluids or from petroleum bearing formations will contain hydrocarbons which adsorb on the surface of drill solid particles and resist removal by washing operations. The volume of the fluid adhering to the discharged cuttings can vary considerably depending on the formation being drilled, the type of drilling fluid being used, the particle size distribution of the cuttings, and the efficiency of the solids control equipment. A general rule of thumb is that five percent (5%) drilling fluid by volume is associated with the cuttings.[11] Data from a drilling project in the Outer Continental Shelf off southern California indicate that the cuttings discharges from the solids control equipment were comprised of 96 percent cuttings and four percent adhered drilling fluids.[15]

For the purpose of estimating pollutant reductions, the total suspended solids (TSS) concentration attributable to drill cuttings is equivalent to the density of the dry weight of cuttings (980 lbs/bbl).[12] This density was estimated from Cook Inlet geologic information provided by the industry,[16] and the specific gravities of low- and high-gravity solids,[17] as follows:

- The first 500 feet of depth consists of high-gravity solids[13] with a specific gravity of 4.5.[17]
- The depth from 500 to 10,000 feet consists of low-gravity solids[13] with a specific gravity of 2.6.[17]
- 50% of the total cuttings volume is generated during the first 3,000 feet.[6]
- The average specific gravity for the first 3,000 feet (50% of the total volume) =
  $$[(4.5 \text{ x } 500 \text{ ft}) + (2.6 \text{ x } 2{,}500 \text{ ft})] / 3{,}000 \text{ ft} = 2.92$$
- The average specific gravity for the remaining depth = 2.6
- The overall specific gravity for drilling cuttings =
  $$(2.92 + 2.6) / 2 = 2.8$$
- The average density of dry cuttings (using water at standard temperature and pressure as a reference) =
  $$2.8 \text{ x } 350 \text{ lbs water/bbl} = 980 \text{ lbs/bbl}$$

4.3 DEWATERING LIQUID CHARACTERISTICS

During site visits to three southern Louisiana drilling operations, EPA collected samples of dewatering centrifuge liquid to determine the quality of this process stream.[1,2,3] This process stream consisted mostly of the water phase of the drilling fluid.

At each drill site, one set of grab samples was collected on two consecutive days from the liquid discharge from a decanting centrifuge that was part of the solids control system (see also Section 5.5.5). The major difference between the three solids control systems was that two of them included chemical treatment of the centrifuge influent to enhance liquid\solid separation, also referred to as chemically enhanced centrifugation (CEC–see Section 5.5.6). The third system used no additional chemicals upstream of the centrifuge. The result was that separation of the colloidal solids from the liquid phase was much more efficient at the two sites using CEC. These samples were relatively free of suspended solids (TSS ranged from 24 to 520 mg/l), while the untreated sample had to be analyzed as a solid due to its solids content (23% to 24.7%), and had the consistency of a drilling fluid.

Table VII-5 compares data obtained from the two sites that used CEC to effluent limits established for this waste stream in a general permit covering drilling waste discharges in the coastal Gulf of Mexico region (58 FR 49126). The dewatering liquid at these sites was being treated for recycle and not for surface discharge. In fact, the majority of these waste volumes was hauled to commercial disposal.[1,2] The solids control contractor at one of these sites suggested that further treatment with activated carbon would produce discharge-quality effluent.[2]

4.4 COOK INLET DRILLING WASTE CHARACTERISTICS

For the purpose of developing compliance cost and pollutant reduction estimates, particular characteristics of drilling wastes in Cook Inlet, Alaska were identified. The sources for these data include the 1993 Coastal Oil and Gas Questionnaire, the EPA Offshore Development Document, direct correspondence with the operators, and calculations and estimates based on the data from these sources. Table VII-4 lists the characteristics of interest, including densities of cuttings and drilling fluid, percentage of solids in drilling fluid, and pollutant concentration data.

BPT limits. Although samples were collected at a number of locations within each facility, samples collected at the effluent of the settling tanks were most representative of BPT level treatment.

Table VIII-3 presents the overall summary of occurrence of the organic pollutants detected in at least 25 percent of the 14 samples of settling tank effluents that were collected. As can be seen from this table, only benzene and toluene were detected in 100 percent of the samples. An additional 18 organic pollutants were detected in greater than 25 percent of the samples. Out of a total of 232 priority and non-conventional organics analyzed, 212 were either not detected, detected in less than 25 percent of the samples, or were removed from consideration because they are not expected to be characteristic of wastewater pollutants discharged in produced water.[5]

Table VIII-4 presents summary analytical data of the settling tank effluents from the 1992 EPA 10 Production Facility Study. Only pollutants that were detected in at least 25 percent of samples are listed. Any non-detected sample results were given the value of one-half the detection limit value in the derivation of the overall mean values. These data were used as BPT-level effluent concentrations for the Gulf of Mexico region in the development of the Coastal Guidelines.

4.2 Composition of Produced Water for Cook Inlet

Table VIII-5 presents the summary data obtained from several sampling programs that are considered to be representative of the composition of produced water in Cook Inlet. The primary source, a comprehensive Cook Inlet Discharge Monitoring Study was conducted by EPA Region 10 to investigate oil and gas extraction point source discharges.[8] In this study, produced water discharges from production facilities in Cook Inlet (coastal subcategory) were sampled and analyzed for one year, from September 1988 through August 1989. Samples were collected from two oil platforms and one natural gas platform, all of which discharge to the surface waters, and also from three shore-based central treatment facilities. Flow-weighted averages were then calculated using the mean concentrations from each discharge in this study. This study, however, only provided data for 10 organic pollutants and zinc. Concentrations for the other pollutants included in Table VIII-5 were taken from the BPT-level effluent data from the Offshore Development Document.[2] EPA determined it appropriate to apply effluent data for offshore platforms to these in Cook Inlet because of the similarities in operation. The data for radium 226 and 228 presented in Table VIII-6 are from the Alaska Oil and Gas Association's comments on the offshore rulemaking.[9]

TABLE VIII-3

PERCENT OCCURRENCE OF ORGANICS FOR BPT LEVEL TREATMENT EFFLUENT SAMPLES FROM THE 1992 EPA 10 PRODUCTION FACILITY STUDY[6]

Pollutant	Number of Independent Samples	Number of Independent Samples w/ Detects	Percent Detects
Benzene	14	14	100.0
Toluene	14	14	100.0
o+p Xylene	14	12	85.7
Ethylbenzene	14	9	64.3
Benzoic Acid	14	9	64.3
m-Xylene	14	8	57.1
Phenol	14	8	57.1
n-Hexadecane	14	7	50.0
Naphthalene	14	8	57.1
o-Cresol	14	8	57.1
Hexanoic Acid	14	8	57.1
n-Tetradecane	14	6	42.9
p-Cresol	14	7	50.0
n-Decane	14	6	42.9
n-Dodecane	14	7	50.0
2,4-Dimethylphenol	14	8	57.1
n-Octadecane	14	6	42.9
n-Eicosane	14	6	42.9
2-Hexanone	14	4	28.6
2-Methylnaphthalene	14	6	42.9

5.0 CONTROL AND TREATMENT TECHNOLOGIES

Treatment processes for produced water are primarily designed to control oil and grease, priority pollutants, and total suspended solids. Currently, most state and NPDES permits that allow the discharge of coastal produced water to surface water bodies with limits only for the oil and grease content (BPT limitation) in the produced water.

5.1 BPT TECHNOLOGY

BPT effluent limitations restrict the oil and grease concentrations of produced water to a maximum of 72 mg/l for any one day, and to a thirty-day average of 48 mg/l. BPT end-of-pipe treatment that can achieve this level of effluent quality consists of some, or all of the following technologies:

- Equalization (surge tank, skimmer tank)
- Chemical addition (feed pumps)

TABLE VIII-4

SUMMARY POLLUTANT CONCENTRATIONS FOR BPT LEVEL EFFLUENT FROM THE 1992 EPA 10 PRODUCTION FACILITY STUDY[6]

Pollutant	Settling Effluent Concentration (μg/l)	Pollutant	Settling Effluent Concentration (μg/l)
CONVENTIONAL AND NON-CONVENTIONAL POLLUTANTS		**PRIORITY POLLUTANT VOLATILE ORGANICS**	
Total Recoverable Oil and Grease	26,600	Benzene	5,200
Total Suspended Solids	141,000	Ethylbenzene	110
Ammonia	41,900	Toluene	4,310
Chlorides	57,400,000		
Total Dissolved Solids	77,500,000	**OTHER VOLATILE ORGANICS**	
Total Phenols	2,430	m-Xylene	147
PRIORITY POLLUTANT METALS		o+p Xylene	110
Cadmium	31.50	2-Hexanone	34.50
Chromium	180	**PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS**	
Copper	236	Naphthalene	184
Lead	726	Phenol	723
Nickel	151	**OTHER SEMI-VOLATILE ORGANICS**	
Silver	359	Benzoic Acid	5,360
Zinc	462	Hexanoic Acid	1,110
OTHER METALS		n-Decane	152
Aluminum	1,410	n-Dodecane	288
Barium	52,800	n-Eicosane	78.80
Boron	22,800	n-Hexadecane	316
Calcium	2,490,000	n-Octadecane	78.80
Cobalt	117	n-Tetradecane	119
Iron	17,000	o-Cresol	152
Magnesium	601,000	p-Cresol	164
Manganese	1,680	2-Methylnaphthalene	77.70
Molybdenum	121	2,4-Dimethylphenol	148
Strontium	287,000	**RADIONUCLIDES**	
Sulfur	12,200	Gross alpha (pCi/l)	675
Tin	430	Gross beta (pCi/l)	367
Titanium	43.80	Lead 210 (pCi/l)	41.30
Vanadium	135	Radium 226 (pCi/l)	189
Yttrium	35.30	Radium 228 (pCi/l)	264

- Oil and/or solids removal
- Gravity separators
- Flotation
- Filters
- Plate coalescers
- Filtration (used prior to subsurface disposal)
- Subsurface disposal (injection).

TABLE VIII-5

PRODUCED WATER POLLUTANT CHARACTERIZATION FOR COOK INLET, ALASKA

Pollutant Parameter	Concentration ($\mu g/l$)
CONVENTIONALS	
Oil & Grease)	35,400[a]
TSS	67,500[b]
PRIORITY METALS	
Cadmium	22.62[b]
Copper	444.66[b]
Lead	195.09[b]
Nickel	1,705.46[b]
Zinc	44.77[a]
PRIORITY ORGANICS	
2,4-Dimethyl phenol	514.70[a]
Anthracene	25.25[a]
Benzene	3,386.12[a]
Benzo(a)pyrene	10.56[a]
Ethyl benzene	157.73[a]
Naphthalene	933.54[a]
Phenol	431.49[a]
Toluene	1,507.43[a]
NON-CONVENTIONALS	
n-Alkanes	1,641.5[b]
Steranes	77.5[b]
Triterpanes	78[b]
Total Xylenes	542.47[a]
Aluminum	78.01[b]
Barium	55,563.80[b]
Boron	25,740.25[b]
Iron	4,915.87[b]
Manganese	115.87[b]
Titanium	7.00[b]
Radium 226	2.65e-06[c]
Radium 228	3.0e-08[c]

[a] Source - Envirosphere, 1989[1]

[b] Source - EPA, January 1993[2]

[c] Source - AOGA, 1991; The values shown were converted from pCi/l to $\mu g/l$ using the conversion factors 1×10^{-6} $\mu g/pCi$ for radium 226 and 3.7×10^{-9} $\mu g/pCi$ for radium 228[7]

Oil is present in produced water in a range of particle sizes from molecular to droplet. Reducing the oil content of produced water involves removing three basic forms of oil: (1) large droplets of coalesceble oil, (2) small droplets of emulsified oil, and (3) dissolved oil. The removal efficiency and resultant effluent quality achieved by the treatment unit is a function of, among other factors, the influent flow, the influent concentrations of oil and grease and suspended solids, and the other types of compounds in the produced water.

The volume of contaminated deck drainage can be reduced by segregating the clean area of the site from the potentially contaminated area.[41] This involves using a segregation berm to separate the office trailer and parking/truck maneuvering areas which generate relatively little pollution from the drilling equipment, pipe racks, production and treatment areas, and waste storage areas. Such a set up which also recycled the dirty water into the mud system was reported to result in a 40% savings to location and waste management costs.[41] The storm water from the non-contaminated side of a drilling or production site would be subject to NPDES requirements for storm water and may require the operator to develop and implement a site-specific storm water pollution prevention plan consisting of a set of BMPs, depending on specific sources of pollutants at each site. A discussion of best management practices is presented in Chapter XVI of this document.

4.0 PRODUCED SAND

Produced sand consists of the accumulated formation sands and other particles (including scale) generated during production as well as the slurried particles used in hydraulic fracturing. This waste stream also includes sludges generated by chemical flocculation used in solids separation processes for produced water such as filtration or sedimentation. The following sections describe the sources, volumes, characteristics, and treatment methods for produced sand.

4.1 PRODUCED SAND SOURCES

Produced sand is generated during oil and gas production by the movement of sand particles in producing reservoirs into the wellbore, by silica material spilling off the face of the producing formation and by the precipitation of scale and other solid particles. The generation of produced sand usually occurs in reservoirs comprised of young, unconsolidated sand formations.[42] Produced sand is considered a solid and consists primarily of sand and clay with varying amounts of mineral scale (epsom salts, magnesite, gypsum, calcite, barite, and celestite) and corrosion products (ferrous carbonate and ferrous sulfide).[43]

Produced sand is carried from the reservoir to the surface by the fluids produced from the well. The well fluids stream consists of hydrocarbons (oil and/or gas), water, and sand. At the surface, the production fluids are processed to segregate the specific components. The produced sand drops out of the well fluids stream during the separation process due to the force of gravity as the velocity of the stream is decreased during passage through the treatment vessels. The sand accumulates at low points in the equipment and is removed periodically through sand drains, manually during equipment shut-downs for cleaning, or by periodic blowdowns as a wet sludge containing both water and oil.[44,45] One source indicates that desanders or desilters (hydrocyclones) are used to remove sand if the volume produced is high.[43] However, observations during the EPA 1992 Production Sampling Program indicate that for lower production volumes more typical of coastal situations, sand removal is primarily achieved by tank cleanouts and that desanders are seldom used.[38] Equipment is typically cleaned on a three to five year cycle. At some locations, sand is collected on a yearly basis because large volumes of sand are being generated due to failure of downhole sand control measures.[45]

4.2 PRODUCED SAND VOLUMES

The generation rate of produced sand will vary between wells and is a function of the amount of total fluid produced, location of the well, type of formation, production rate and completion methods.[43,44] Oil producing reservoirs will typically generate more produced sand than gas producing reservoirs. This is because oil reservoirs generate more liquids (both oil and water) which are more viscous than gas and thus the liquids will remove and carry the sand more easily to the surface than gas. Also, the greater water volumes associated with oil reservoirs will create more scale particles. Another reason is because gas producing wells have sensors that detect sand flowing with the gas stream to prevent erosion on the production equipment due to sand flowing with the gas at high velocities.[46] Table IX-20 presents a summary of the produced sand volumes data.

4.2.1 Gulf of Mexico

224 production separation facilities in the Gulf of Mexico provided produced sand data in the 1993 Coastal Oil and Gas Questionnaire.[8] Of these 224, a total of 37 facilities reported produced sand generation volumes. The average volume generated was 74 bbls. Since produced sand is not collected from process equipment every year, the survey only represents a snapshot of produced sand collection for the year of 1992. The average frequency of generation of produced sand for these 37 facilities ranged between 2.2 times per year and once every 2.9 years. Although only 16.5% of the facilities reported produced sand volume data, this does not indicate that 83.5% of the facilities did not generate any produced sand that year. It indicates that either these facilities did not generate any produced sand, or no produced sand was collected from the process equipment for that year, or that the volume was unknown.

The annual sand generation rates obtained during EPA's 1992 10 production facility study ranged from 106 to 400 bbls for facilities with produced water flowrates of 6,462 and 7,000 bpd respectively.[38] In addition, one of the two commercial produced water injection facilities sampled by EPA in 1992

TABLE IX-20
PRODUCED SAND VOLUMES GENERATED

	Gulf of Mexico		Cook Inlet	
Source	Produced Sand Generated	Frequency	Produced Sand Generated	Frequency
Oil & Gas Questionnaire	74 bbls[a]	1/2.9 yr[a]	365 bbl[8] 1 bbl[8] 1 bbl[8] 1 bbl[8]	--
Trip Reports	106 bbls[38] 400 bbls[38]	1/1 yr[38] 1/1 yr[38]	600 bbl[22]	½ +yr[22]

[a] Estimated average from SAIC, September 30, 1994.[5]

reported an annual sand generation rate of 50 bbls with an average produced water flowrate of 5,000 bpd.[47] It is likely that some of the produced sand in the produced water received by the commercial facility would have settled out in the production equipment and produced water storage tanks prior to being sent to commercial disposal.

The Coastal Oil and Gas Questionnaire indicates that only one of the operators surveyed discharged produced sand at three of its facilities in 1992. The operator indicated that this practice would be discontinued in the near future.[48] All other operators dispose of produced sands via landfarming, underground injection, landfilling, or onsite storage. The total sand production from the three sites discharging sand was 144 bbls which is a small proportion of produced sand generated in the region.

4.2.2 Cook Inlet

Four of the platforms in Cook Inlet reported produced sand generation volumes in the 1993 Coastal Oil and Gas Questionnaire.[8] One reported generating 365 bbls in 1992 while the remaining three reported only one bbl for 1992. Operators of the Bruce Platform in Cook Inlet reported that they had removed 600-bbls of produced sand for disposal from their two 600-bbl produced water settling tanks two years prior to EPA's visit in August 1993.[22] Therefore, the amount generated per platform can vary greatly. The current produced sand disposal practice in Cook Inlet is zero discharge via land disposal and storage for future land disposal.[49,50] In the past, produced sand from the Bruce Platform had been sent to the Kenai

Gas Field for storage. This produced sand has recently been ground and injected as part of a pilot project to grind and inject stored wastes and the contents of old reserve pits.[23]

4.3 PRODUCED SAND CHARACTERIZATION

Produced sand is generally contaminated with crude oil from oil production or condensate from gas production. The primary contaminant associated with produced sand is oil.[12] The oil content of unwashed produced sand can range from a trace (expected in sand from blowdown) to as much as 19 percent by volume.

During the EPA 1992 Production Sampling effort, samples of settling tank bottoms were collected at four facilities and analyzed for conventional, non-conventional, organic pollutants and metals and radionuclides.[38] These samples are considered representative of produced sand. Table IX-21 presents the maximum and minimum observed concentrations detected in these samples. In cases of a single detect for a particular pollutant, the detected concentration value is reported in Table IX-21 as the maximum observed concentration. Due to a limited volume available at some of these sites, not all analytes were analyzed for all of the samples. For the two samples that were analyzed for oil content, the concentration ranged from 12.7 to 19 percent. All toxic metals were present except silver, with most notable contributions from copper (32.15 mg/kg) and lead (171.94 mg/kg).[51] The toxic organic pollutants present were similar to those found in produced water including benzene, ethylbenzene, toluene, xylene, propanone, and phenanthrene.

4.4 PRODUCED SAND CONTROL AND TREATMENT TECHNOLOGIES

The primary control and treatment technology for produced sand is preventing the sand from exiting the formation. Sand control is determined by the type of well completion. A specialized completion can prevent sand from being brought into the production line with the fluids.[46] The most up-to-date completion technology will prevent production solids from entering the production tubing, even in loose and unconsolidated formations.

The most common type of completion that prevents solids from entering the production tubing is a gravel pack completion. A gravel pack completion is a perforated cased hole completion that includes the placement of gravel, glass beads, or some other packing material between the production tubing and the casing. A screen or mesh is also placed between the production tubing and the casing. The gravel pack and screen serve as a filter to prevent solids from entering the production tubing. Older wells are

TABLE IX-21

RANGE OF POLLUTANT CONCENTRATIONS IN PRODUCED SAND FROM THE 1992 COASTAL PRODUCTION SAMPLING PROGRAM[51]

Pollutant	Units	Number of Samples	Number of Detects	Minimum Value	Maximum Value
CONVENTIONAL AND NON-CONVENTIONAL					
Total Recoverable Oil & Grease	µg/kg	3	3	84,000.00	328,562.87
Oil Content	%	2	2	12.70	19.00
Total Solids	µg/kg	3	3	76.00	1,052,084.21
BOD 5-day (Carbonaceous)	µg/kg	3	3	16,000.00	161,413.51
Total Organic Carbon (TOC)	µg/kg	3	3	20,000.00	285,693.11
Ph	Ph	3	3	6.70	10.50
Chloride	µg/kg	3	3	1,360.78	25,000.00
Fluoride	µg/kg	3	3	1.30	368.25
Nitrate/Nitrite	µg/kg	3	1	(a)	19.00
Total Releasable Sulfide	µg/kg	3	1	(a)	200.00
Total Sulfide (Isometric)	µg/kg	3	2	26.14	2,000.00
PRIORITY POLLUTANT METALS					
Antimony	mg/kg	4	1	(a)	4.50
Arsenic	mg/kg	4	2	8.30	34.00
Beryllium	mg/kg	4	3	0.10	0.20
Cadmium	mg/kg	4	2	0.93	2.20
Chromium	mg/kg	4	4	3.70	26.60
Copper	mg/kg	4	4	6.50	72.00
Lead	mg/kg	4	4	25.70	510.00
Mercury	mg/kg	4	1	(a)	0.20
Nickel	mg/kg	4	4	4.90	12.50
Selenium	mg/kg	4	1	(a)	4.00
Thallium	mg/kg	4	1	(a)	2.70
Zinc	mg/kg	4	4	63.80	11,700.00
NON-PRIORITY POLLUTANT METALS					
Aluminum	mg/kg	4	4	879.00	71,100.00
Barium	mg/kg	4	4	201.00	3,680.00
Boron	mg/kg	4	4	26.80	328.00
Calcium	mg/kg	4	4	6,020.00	23,500.00
Cobalt	mg/kg	4	4	1.70	3.50
Iron	mg/kg	4	4	4,650.00	14,300.00
Magnesium	mg/kg	4	4	602.00	3,030.00
Manganese	mg/kg	4	4	54.50	121.00
Molybdenum	mg/kg	4	2	1.60	15.70
Sodium	mg/kg	4	4	13,300.00	32,800.00
Strontium	mg/kg	2	2	131.00	256.00
Sulfur	mg/kg	4	4	1,570.00	5,890.00
Tin	mg/kg	4	3	3.80	349.00
Titanium	mg/kg	4	4	14.60	60.80
Vanadium	mg/kg	4	4	2.90	18.60
Yttrium	mg/kg	4	4	2.30	5.80
PRIORITY POLLUTANT VOLATILE ORGANICS					
Benzene	µg/kg	3	3	55,352.86	283,445.00
Ethylbenzene	µg/kg	3	3	33,170.00	296,995.00
Methylene Chloride	µg/kg	3	2	193.37	54,140.35

TABLE IX-21 - *Continued*

RANGE OF POLLUTANT CONCENTRATIONS IN PRODUCED SAND FROM THE 1992 COASTAL PRODUCTION SAMPLING PROGRAM[51]

Pollutant	Units	Number of Samples	Number of Detects	Minimum Value	Maximum Value
CONVENTIONAL AND NON-CONVENTIONAL					
Toluene	µg/kg	3	3	89,417.14	355,835.00
Trichlorofluoromethane	µg/kg	3	2	30,707.14	250,754.39
NON-PRIORITY POLLUTANT VOLATILE ORGANICS					
M-Xylene	µg/kg	3	3	18,827.14	161,610.00
O+P Xylene	µg/kg	3	2	70,039.68	116,645.00
2-Propanone	µg/kg	3	1	(a)	222,183.05
PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS					
Acenaphthene	µg/kg	3	1	(a)	8,511.33
Anthracene	µg/kg	3	1	(a)	10,442.33
Fluorene	µg/kg	3	2	12,115.33	19,521.00
Naphthalene	µg/kg	3	3	46,547.00	57,003.33
Phenanthrene	µg/kg	3	2	19,739.00	26,779.67
2,4,6-Trichlorophenol	µg/kg	3	1	(a)	139,153.33
NON-PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS					
Acetophenone	µg/kg	3	1	(a)	50,996.67
Biphenyl	µg/kg	3	2	25,620.33	50,769.33
Dibenzofuran	µg/kg	3	1	(a)	15,397.00
Dibenzothiophene	µg/kg	3	2	4,873.33	6,826.33
n-Decane	µg/kg	3	3	7,302.67	169,263.33
n-Docosane	µg/kg	3	3	53,659.33	199,183.33
n-Dodecane	µg/kg	3	3	50,642.33	716,843.33
n-Eicosane	µg/kg	3	3	139,153.33	333,090.00
n-Hexacosane	µg/kg	3	3	20,380.00	123,716.67
n-Hexadecane	µg/kg	3	3	250,070.00	554,033.33
n-Octacosane	µg/kg	3	3	5,543.67	150,746.67
n-Octadecane	µg/kg	3	3	225,183.33	463,686.67
n-Tetracosane	µg/kg	3	3	64,200.00	187,440.00
n-Tetradecane	µg/kg	3	3	253,220.00	439,433.33
n-Triacontane	µg/kg	3	3	16,789.00	393,873.33
1-Methylfluorene	µg/kg	3	3	31,473.33	88,670.00
1-Methylphenanthrene	µg/kg	3	2	10,717.33	38,270.00
1-Phenylnaphthalene	µg/kg	3	1	(a)	5,124.00
2-Isopropylnaphthalene	µg/kg	3	1	(a)	39,190.00
2-Methylnaphthalene	µg/kg	3	2	96,533.33	155,923.33
2-Phenylnaphthalene	µg/kg	3	2	6,012.00	6,871.33
3,6-Dimethylphenanthrene	µg/kg	3	1	(a)	62,333.33
4-Aminobiphenyl	µg/kg	3	1	(a)	31,025.67
RADIONUCLIDES					
Gross Alpha	pCi/g	4	1	(a)	872.00
Gross Beta	pCi/g	4	4	12.00	668.00
Lead 210	pCi/g	4	3	4.20	11.70
Radium 226	pCi/g	5	4	2.60	6.90
Radium 228	pCi/g	5	3	2.70	6.50

(a) Analyte detected in only one sample; the detected value is reported as the maximum.